IDAHO POWER®
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September 30, 2014

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case No. IPC-E-13-14
Continuation of Demand Response Programs – Demand Response as Operating Reserves Feasibility Report

Dear Ms. Jewell:

In the Settlement Agreement signed by parties to Case No. IPC-E-13-14, Idaho Power Company committed to investigating the feasibility of using demand response as operating reserves and making a determination on feasibility by the end of the 3rd quarter in 2014.

Enclosed for filing in the above matter are an original and three (3) copies of Idaho Power Company's Demand Response as Operating Reserves Feasibility Report. The study will be presented to the Energy Efficiency Advisory Group in an upcoming meeting.

Idaho Power Company is providing these informational copies for the Idaho Public Utilities Commission's records and convenience. Please contact me at (208) 388-6117 if you have any questions.

Very truly yours,

Julia A. Hilton

JAH:kkt
Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 30th day of September 2014 I served a true and correct copy of IDAHO POWER COMPANY'S DEMAND RESPONSE AS OPERATING RESERVES FEASIBILITY REPORT, upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Karl Klein Deputy Attorney General Idaho Public Utilities Commission 472 West Washington (83702) P.O. Box 83720 Boise, Idaho 83720-0074	____ Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email karl.klein@puc.idaho.gov
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Idaho Conservation League Benjamin J. Otto Idaho Conservation League 710 North Sixth Street Boise, Idaho 83702	____Hand Delivered ____ U.S. Mail ____Overnight Mail ____FAX _X_ Email botto@idahoconservation.org
Snake River Alliance Ken Miller, Clean Energy Program Director Snake River Alliance P.O. Box 1731 Boise, Idaho 83701	____Hand Delivered ____ U.S. Mail ____Overnight Mail ____FAX _X_ Email kmiller@snakeriveralliance.org
Industrial Customers of Idaho Power Peter J. Richardson RICHARDSON ADAMS, PLLC 515 North 27th Street (83702) P.O. Box 7218 Boise, Idaho 83707	____Hand Delivered ____ U.S. Mail ____Overnight Mail ____FAX _X_ Email peter@richardsonadams.com

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Kimberly Towell, Executive Assistant

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DEMAND RESPONSE AS OPERATING RESERVES FEASIBILITY REPORT

September 30, 2014

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EXECUTIVE SUMMARY

In Settlement Agreements filed in both Idaho and Oregon[1] and approved by the Idaho Public Utilities Commission ("IPUC") and the Public Utility Commission of Oregon ("OPUC") in Order Nos. 32923 and 13-482, respectively, Idaho Power Company ("Idaho Power" or "Company") agreed to investigate the feasibility of using Demand Response ("DR") as operating reserves and to make a determination on the feasibility by the end of the 3rd quarter of 2014.

The Demand Response as Operating Reserves Feasibility Report ("Report") provides a background of the Company's operating reserves requirements, and identifies that DR could only be used for the non-spinning portion of the Company's Contingency Reserves Obligation ("CRO"). It describes each of the DR programs the Company currently operates, discusses the applicability of using DR as CRO from a compliance perspective, and describes the implementation requirements for the Company to use its DR programs as CRO. The Report then examines each of the DR programs and discusses whether or not each one has potential to be used as CRO. The Report concludes with the Company's financial analysis and recommendation.

Based on its analysis, Idaho Power concluded the risks outweigh the benefits to utilize DR as CRO because: (1) the economic benefit of using DR as CRO is too small to provide incentives at a level that would attract participation and provide for program costs, (2) the risks for failure to meet North American Electric Reliability Corporation ("NERC") standards is far greater than the economic benefit that might be derived, (3) the period of testing that would be required to provide operational certainty of compliance with NERC and Western Electricity Coordinating Council ("WECC") requirements would require carrying substantially more than the reserves actually needed for contingency, at a cost to all customers, and (4) the number of CRO events would put too heavy of a strain on the DR participants, thus risking participation in the Company's DR programs.

As described in the Report, the economic benefit, excluding payments to participants and program costs, of using DR as CRO is insignificant when compared to the capacity benefit the current DR programs provide. While having a dual-purposed program may be conceivable from a technical and compliance perspective, the Company believes that it is not practical from an economic and DR program participant perspective. The Company believes that the economic, DR program participation and other operational risks identified in this Report, are too great to proceed with a pilot at this time.

[1] Idaho Case No. IPC-E-13-14 and Oregon Case No. UM-1653.

Introduction

In late 2012 and early 2013, Idaho Power filed for changes to its A/C Cool Credit program, Irrigation Peak Rewards program, and FlexPeak Management program (collectively "DR Programs") in both its Idaho and Oregon jurisdictions.[2] These filings were prompted by the lack of near-term peak-hour deficits identified in the Peak Load and Resource Balance analysis prepared for the 2013 Integrated Resource Plan ("IRP"), and Idaho Power's desire to take prompt and prudent steps to avoid some of the expenses associated with the programs in years where the Peak Load and Resource Balance analysis did not show a need.

In Order No. 32823, the IPUC opened Case No. IPC-E-13-14, and set an informal prehearing conference to be held on June 12, 2013, to schedule workshops to evaluate Idaho Power's DR Programs for the 2014 program season and beyond. The IPUC ordered that the Idaho Irrigation Pumpers Association ("IIPA"), the Idaho Conservation League ("ICL"), and the Snake River Alliance ("SRA") were designated as intervening parties in this case. Additional petitions to intervene in this proceeding were filed by the Industrial Customers of Idaho Power ("ICIP") and EnerNOC, Inc. ("EnerNOC").

In the interest of administrative efficiency for the OPUC and for the Oregon customers of Idaho Power, in May of 2013, the OPUC opened Docket No. UM 1653 to facilitate participation by OPUC Staff and interested Oregon parties in the Idaho workshop process.

Following the June 12, 2013, prehearing conference, the parties set a schedule for four workshops, which were held on July 10, July 23, August 7, and August 19. During the August 19 workshop, the participants agreed to hold an additional workshop on August 27, 2013, which included confidential settlement discussions. An additional workshop was held in Oregon for the benefit of interested Oregon parties on October 9, 2013, where the results of the prior workshops were reviewed, questions were answered, and parties held settlement discussions.

Based upon the Idaho proceedings, several parties, including Idaho Power, IPUC Staff, IIPA, ICL, SRA, EnerNOC, and non-party customer Mike Seaman agreed to resolve and settle issues related to the reinstatement of Idaho Power's DR Programs for 2014 and beyond. The signed Settlement Agreement was approved by the IPUC in Order No. 32923. The Company filed a similar Settlement Agreement with the OPUC in Docket No. UM 1653, which was approved by Order No. 13-482. Both Settlement Agreements are working as envisioned and during the 2014 DR program season the Company had enrolled DR participants to provide approximately 390 megawatts ("MW") of maximum load reduction at generation level, which is near prior levels of DR capacity before the programs were temporarily suspended in 2013.

[2] Idaho Docket Nos. IPC-E-12-29, IPC-E-13-04, Oregon Advice 13-04 and Docket No. UM-1653.

In these Settlement Agreements, Idaho Power agreed to investigate the feasibility of using DR as operating reserves and make a determination on the feasibility by the end of the 3rd quarter of 2014.[3]

This Report presents the Company's feasibility review and recommendation not to use DR as operating reserves. First, the Report will provide a regulatory and operational overview of the Company's operating reserves requirements and will then describe each of the DR Programs the Company currently operates. The Report will then discuss the applicability of using DR as operating reserves from a compliance perspective and describe the implementation requirements for the Company to use its DR Programs as operating reserves. The Report will then examine each of the DR Programs and discuss why the DR Programs should not be used as operating reserves.

Regulatory and Operational Overview

For operation of its Bulk Electric System ("BES"), Idaho Power is regulated by the Federal Energy Regulatory Commission ("FERC") who oversees the NERC, as the Electric Reliability Organization ("ERO") for North America, a requirement of the Federal Power Act of 2006. NERC is the entity that develops and enforces the mandatory Reliability Standards that Idaho Power must adhere to, governed by Section 215 of the Federal Power Act. In addition to adhering to NERC Standards, Idaho Power is a member of the WECC, the Regional Entity responsible for coordinating and promoting BES reliability in the Western Interconnection.

Operating Reserves

NERC and WECC standards require that the Company hold a certain amount of operating reserves to ensure reliable operation of the system. NERC defines operating reserves as "that capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection,"[4] or simply, the generation capacity required above the Company's load for possible contingency events, changes in load, and accommodation for variable generation. Operating reserves are comprised of Contingency Reserve[5] Obligations ("CRO") and Regulating Reserves.[6]

CRO is the amount of generation capacity generally held for use for events such as generator trips resulting in loss of generation or transmission line trips resulting in loss of import energy, while Regulating Reserve is the unloaded generation capacity

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[3] Demand Response Programs Settlement Agreement at 4.

[4] NERC's Glossary of Terms Used in NERC Reliability Standards: http://www.nerc.com/files/glossary_of_terms.pdf

[5] NERC defines Contingency Reserve as "the provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements." *Id.*

[6] NERC defines Regulating Reserve as "an amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin." *Id.*

generally used for moment to moment changes in both load and variable generation. Typically the Company's CRO must have at least 50 percent met by Spinning Reserves,[7] with the remaining met with Non-Spinning Reserves[8] while Regulating Reserves are comprised completely of Spinning Reserves. Spinning Reserves is unloaded generation capacity that is online and synchronized to the electrical system while Non-Spinning Reserves is generation or load that can be dispatched and utilized within 10 minutes.[9]

In terms of managing and maintaining its operating reserves, Idaho Power is required to adhere to the following NERC and WECC standards: the Real Power Balancing Control Standard (BAL-001), the Disturbance Control Performance Standard (BAL-002), the Frequency Response and Frequency Bias Setting Standard (BAL-003), the Contingency Reserve Standard (BAL-002-WECC-2), and the Northwest Power Pool Reserve Sharing Agreement. Ultimately, Idaho Power must be able to meet the Most Severe Single Contingency ("MSSC") (BAL-002) with CRO, which for Idaho Power is 330 MWs, and equivalent to the loss of two units at the Jim Bridger Power Plant.

Because DR is not generation, it can only be used to satisfy the non-spinning portion of the Company's CRO, and as such, the remainder of this Report will focus on the CRO rather than total operating reserves, which are comprised of both CRO and Regulating Reserves.

CRO at Idaho Power

Generally, the Company's CRO is met by utilizing hydro generators that have reservoir storage available to provide the rapid response for the extended time needed, but other

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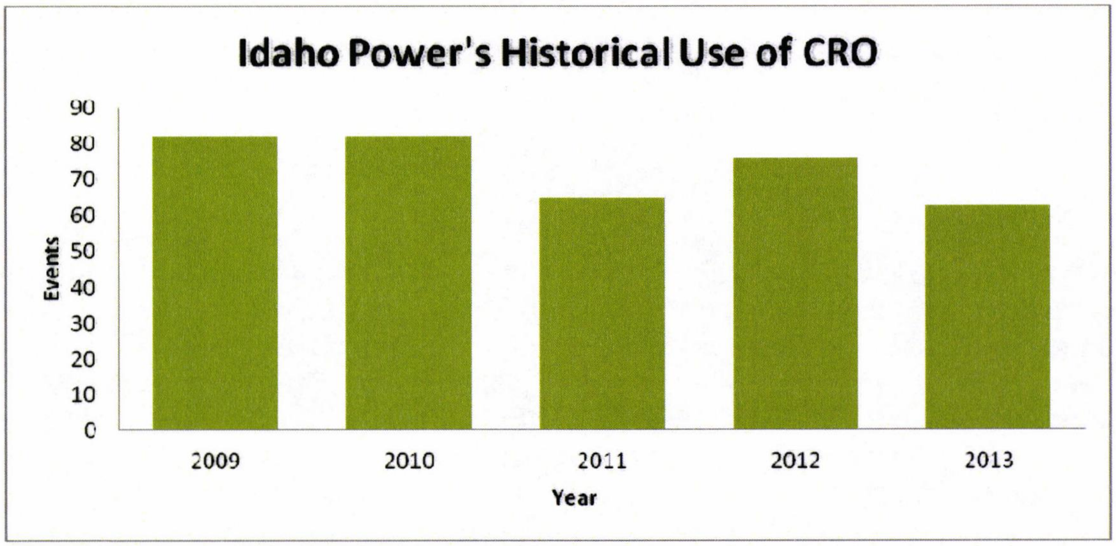
[7] NERC defines Spinning Reserve as "unloaded generation that is synchronized and ready to serve additional demand." *Id.*

[8] NERC defines Non-Spinning Reserve as "that generating reserve not connected to the system but capable of serving demand within a specified time" or "interruptible load that can be removed from the system in a specified time." *Id.*

[9] The 10 minute requirement is mandated by the Reserve Sharing Agreement Idaho Power adheres to as a member of the Northwest Power Pool.

types of generation used for reserves include the Company's thermal fleet that has demonstrated the ability to respond within the 10 minute timeframe. When used as reserves, these hydro or thermal plants have their generation output reduced and held in reserve to provide the capacity that can be activated when needed.

The number of times Idaho Power uses its CRO varies widely and is not predictable by day, duration, or number of MWs. The Company called on its CRO 82, 82, 65, 76, and 63 times during the years 2009 through 2013, respectively. The events spanned all seven days of the week, all 12 months of the year, and the number of MWs called on ranged from as few as two to as many as 171 during a single event. The chart below demonstrates how many times over the prior five years Idaho Power has called on its CRO.



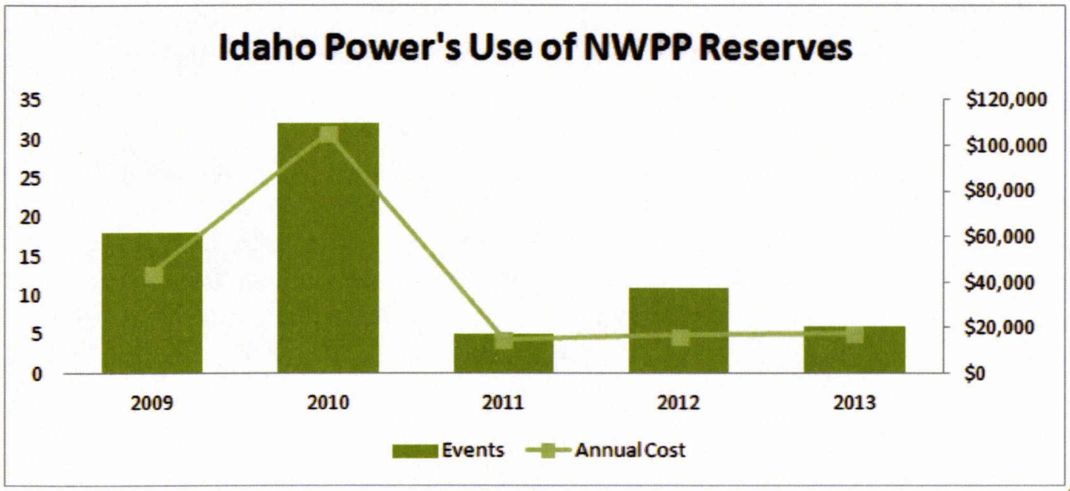
Northwest Power Pool

In addition to utilizing its own resources to meet its CRO, Idaho Power is a member of the Northwest Power Pool ("NWPP"), which is registered with WECC as a Reserve Sharing Group ("RSG") for compliance with the NERC Standard BAL-002 and the WECC Regional Standard BAL-002-WECC-2. By participating in the NWPP RSG, Idaho Power is able to reduce its overall Company-held CRO requirement to approximately half of its 330 MW MSSC.[10] As a member of a RSG, Idaho Power can utilize the reserves of other members in the event that it has exhausted its CRO. Conversely, other RSG members can request Idaho Power to deliver its CRO to assist in the mitigation of contingency events. The energy requested by the other NWPP members may not exceed Idaho Power's CRO. The operating agreements of the NWPP RSG allow for the real-time sharing of energy assistance without prior transmission reservations or payment for reserved generation capacity.

[10] Idaho Power's CRO is determined based on the following formula: CRO = (5% * Hydro Generation) + (7% * Thermal Generation). For the most recent 12 month period, the average CRO held was 113 MW.

NWPP RSG participants, like Idaho Power, differ from those entities that are bidding into an organized market for energy and capacity because the ability to call on the NWPP RSG allows the Company to reduce the amount of reserves it holds as capacity. Conversely, entities who operate in a Regional Transmission Organization ("RTO") or Independent System Operator ("ISO") market bid into that market based on each utility's relative costs of energy *and* capacity, and the market determines which resources are utilized to supply the needs of the entire RTO/ISO balancing area. Those costs are then spread across all participants in that balancing area.

The Company called on the NWPP RSG reserves 18, 32, 5, 11, and 6 times during the years 2009 through 2013, respectively. The events spanned all seven days of the week, all 12 months of the year, and the number of megawatt-hours called ranged from as few as one to as many as 599 during a single event. The chart below demonstrates how many times over the prior five years Idaho Power has called on the NWPP RSG (primary axis), and the annual dollars spent for all events (secondary axis). In the event that Idaho Power utilizes the NWPP RSG, it pays for that energy based on a market value[11] at the time of an event, so the Company is only paying for the market value of the energy and is not paying to reserve generation capacity or for transmission.



Demand Response Programs at Idaho Power

Idaho Power has three DR programs available for and tailored to each of its Residential, Large Commercial & Industrial ("C&I"), and Irrigation customer classes.

A/C Cool Credit is a voluntary DR program available to the Company's residential customers. Using communication hardware and software, Idaho Power cycles participants' central air conditioners ("A/C") or heat pumps off and on via a direct-load control device installed on the units. The program is available during summer peak

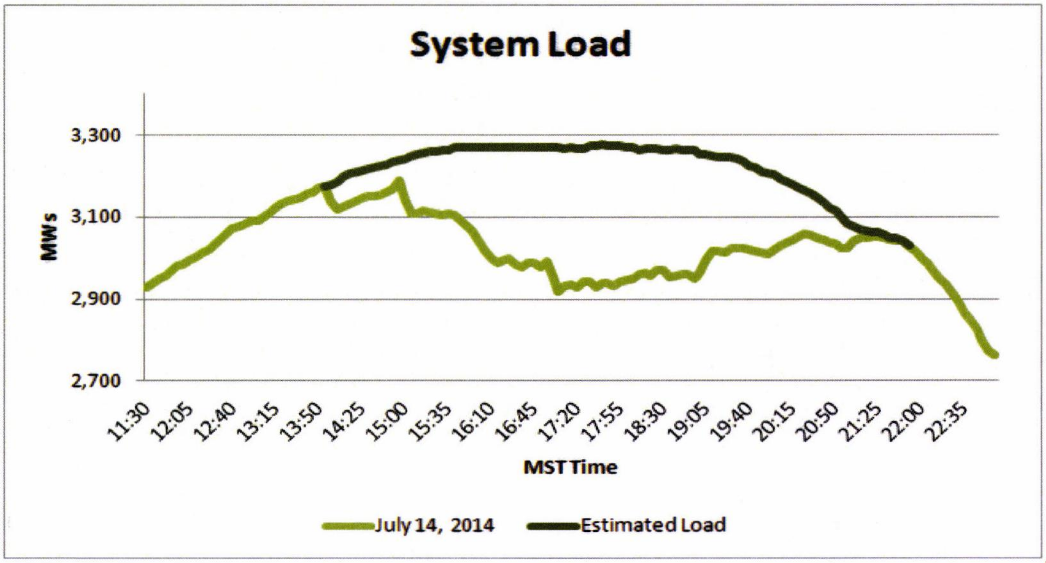
[11] For purposes of the Reserve Sharing Program, the settlement price will be the average of the Powerdex Mid-Columbia hourly price for (1) the hour during which the participant first requests Assistance Reserve (the "Request Hour") and (2) each of the two hours immediately following the Request Hour; provided, however, that in no event will the settlement price be less than zero or greater than the price cap in effect for the WECC in accordance with regulations and orders of FERC in effect as of the Request Hour.

periods between June 15 through August 15 with maximum event durations of four hours, and maximum event hours during the season of 60.

FlexPeak Management is a voluntary DR program available to the Company's C&I customers capable of reducing their electrical energy consumption for short periods of time. The program is administered by Idaho Power through a third-party aggregator and relies on customers voluntarily reducing use at their sites when they are notified of an event. The program is available during summer peak periods between June 15 through August 15 with maximum event durations of four hours, maximum event hours during a season of 60, and the maximum number of events called during a season of 20.

Irrigation Peak Rewards is a voluntary DR program that is available to the Company's agricultural irrigation customers. The program pays irrigation customers a financial incentive for the ability to turn off participating irrigation pumps at potential high system demand periods. The program is available during summer peak periods between June 15 through August 15 with maximum event durations of four hours, maximum event hours during a calendar week of 15, and maximum event hours during a season of 60. Irrigation Peak Rewards has three options for customer participation: two that are dispatched via direct-load control devices and a third manual interruption option that does not utilize a direct-load control device, but rather relies on participants to manually interrupt their loads when notified of an event.

During the 2014 season, Idaho Power's DR Programs were all utilized, with each program being dispatched three times. The chart below represents the estimated demand reduction achieved on July 14, 2014, when all three programs were dispatched on the same day. The nighttime and daytime temperatures that day were 73 and 103 degrees, respectively. The estimated reduction was based on real-time forecasting of the system loads, and based on that estimate, the DR Programs provided approximately 375 MW of peak load reduction.



Applicability

Idaho Power's research indicates that NERC and WECC standards would allow the use of DR as a non-spinning reserve. In order to be compliant with the standards, Idaho Power must ensure that it is able to: (1) accurately measure the amount of reserves claimed, (2) guarantee all reserves are activated within 10 minutes, and (3) maintain documentation to be provided during a NERC/WECC audit.

In order to ensure that the DR resource would perform as required when dispatched to provide CRO, the Company would require that a program be designed and implemented for a two-year period in order to ensure that the amount of CRO expected to be provided by the DR resource can be achieved 100 percent of the time in the required timeframes. The Company believes that for it to be able to depend on DR to provide all or a portion of CRO when needed, sufficient testing must be done to ensure deliverability of the load reduction that DR would provide under various system conditions. As noted earlier, the average CRO required by Idaho Power over the most recent 12 months was 113 MW, and for the Company to understand how it could use DR to meet a portion of that requirement, it would need to gain enough data during that two-year period to determine how much DR it could confidently integrate into the overall CRO requirement.

Further, to ensure compliance with the above-mentioned standards, if it were to use DR as part of its CRO, Idaho Power would require that its Real-Time Operators ("Operators") will have direct control over the resource. As system events occur, the Operators are evaluating system conditions to determine the appropriate action to take, and as the Operators execute these actions they are re-evaluating in real-time to ensure that the expected results are accomplished. By having direct-load control over the resource, the Operators can ensure that the expected load response occurs in time to comply with the NERC regulations, and in the event the expected load response does not occur, the Operator will immediately take additional actions to comply with the regulations. All of the Operators' actions are critical to maintaining the reliability of the electrical grid, and most importantly, all must be executed within a 10 minute period.

Lastly, Idaho Power is required to maintain auditable documentation to be provided to NERC/WECC, as requested at any time. At a minimum of once every three years, audits of this documentation are conducted by WECC, NERC, and occasionally FERC.

Implementation Considerations

Based on the requirements discussed earlier, the Company evaluated its current operations, systems and limitations to identify what modifications would need to be made to use DR as CRO. The Company also analyzed each of its three DR programs to determine the ability to use each as CRO and whether or not that program was a possible "fit" for providing CRO. In considering each program, the Company looked at several factors, including: whether or not there was a direct-load control device installed as a requirement of the DR program, the ease or difficulty of forecasting the demand reduction achieved by the program, the number of hours/days the DR program would be available as CRO, the size of the DR program in MWs and number of participants, and program participant notification requirements.

Operation System Modifications

The Company's existing Load Serving Operations' ("LSO") systems would need to undergo significant upgrades to be able to incorporate the use of DR as CRO. These upgrades include integration of the dispatch system(s) for each program to the Energy Management System ("EMS") and development of a fully integrated DR forecasting tool.

The EMS network consists of one or more control centers and Supervisory Control and Data Acquisition ("SCADA") connections to many field locations, typically substations. Field equipment takes measurements and sends data back to the control center to provide situational awareness to Operators. Those Operators have the ability to control field equipment through the SCADA network. Because the current EMS is not integrated with the other communication systems necessary to dispatch any DR resource, modifications would be required. In order to respond within the required 10 minute period, the Operator needs a specific tool that presents the forecasted load for any DR providing CRO. The current forecasting tools for all three of the Company's DR programs do not provide day ahead or real-time components, only a weekly generalized forecast. System modifications would be required to ensure that the forecast of DR on the system is being constantly updated with the most current data available. The updated systems would need to be able to quickly determine how much load reduction is achieved from DR and to continually update the forecast that the Operators are relying on for optimum accuracy.

A/C Cool Credit

The A/C Cool Credit program provides approximately 33 MW of load reduction if dispatched when temperatures are near 100 degrees throughout the program's season of June 15 through August 15. The program requires the installation of direct-load control devices as a provision of participation, which means the Company could utilize existing infrastructure if it determined the program was viable to use as CRO. The program currently uses one system to dispatch all events, so any necessary LSO system modifications would only require integration with that one system.

The current program cycles A/C units off and on between June 15 and August 15, but the Company believes that its A/C load could only provide substantial and reliable load reduction during certain hours of certain days during that time period. The program season could be expanded, but likely would not provide very much benefit due to the reduced A/C load during much of the summer.

There are many factors that influence the amount of load reduction the Company may experience during an event, including the temperature on the day of the event, the daytime and nighttime temperatures of the days leading up to the event, the time of day the event is called, and the amount of cycling (percent of time the unit is off) that is utilized. Generally, the Company would anticipate receiving about one kilowatt ("kW") per participant on a 100 degree or higher day, so long as those A/C units were on at the time of the event. Based on these factors, the amount of load available for CRO from the A/C Cool Credit program would be small and would vary dramatically hour by hour and day by day.

In addition, because customers have the ability to "opt out" of a single event, or the entire program at anytime, the Company and its contractor must be staffed during events to receive participant inquiries. Extending the program for its use as CRO would likely increase the labor costs of the program because the program could be called as CRO outside of normal business hours when the Company and its contractor currently do not have adequate staff available.

FlexPeak Management

The FlexPeak Management program provides approximately 38 MW of load reduction during events called throughout the program's season of June 15 through August 15. While the third-party aggregator does have a handful of sites where there are direct-load control devices installed, most customers are in control of curtailing their own load at a participating site, and Idaho Power does not have direct control over any of the devices. For this reason, it is not feasible to consider the FlexPeak Management program for use as CRO, due to the requirement that Operators have direct control over the resource and that the resource must be fully dispatched within 10 minutes of an event starting.

Irrigation Peak Rewards

The Irrigation Peak Rewards program provides approximately 319 MW of load reduction during events called throughout the program's season of June 15 through August 15. Irrigation Peak Rewards has three options for customer participation: two that are dispatched via direct-load control devices (approximately 240 MW) and a third manual interruption option that does not utilize a direct-load control device, but relies on participants to manually interrupt their loads (approximately 60 MW).

The program is currently structured to be used between June 15 and August 15, but the Company believes that its irrigation load could provide potential load reduction from mid-April through the end of September. Irrigation load typically runs at all hours of the day, so the Company believes that logistically, it is reasonable to expect Irrigation Peak Rewards could provide some level of CRO at most all hours of the day during the identified time period, (although this is difficult to predict based on the unpredictability of weather and the variability of crop characteristics). The Company believes it would be complicated to forecast the irrigation load available in the program for CRO each hour of each day throughout the irrigation season, but with modifications to the existing systems it could be done.

Lastly, because the Company would require that direct-load control devices are used to curtail load, only the first two options would be viable for consideration of the program as CRO. Based on current participation in the program, these two resources have the ability to provide approximately 240 MW of load curtailment.

Evaluating DR as a CRO

Costs

In order to provide Operators with a tool to effectively and reliably use DR as CRO, several modifications to the Company's existing technological infrastructure would be required. The current system configuration is not set up to directly dispatch DR in the timeframe necessary. The system modifications described below would enable the Operators to dispatch the DR resource within 10 minutes, as required by the WECC Reliability Standard BAL-002-WECC. The current system would also require a fully integrated real-time forecasting component necessary to assist the Operators in accurately determining the expected hourly DR load reduction.

- Modify the existing EMS to ensure the capability to dispatch the DR resources, providing visibility to Operators of available DR resources and with the ability to easily dispatch those resources in a timely manner. *Estimated Cost: $50,000*
- Develop or procure an application that accurately forecasts on an hourly basis the currently available DR on the Idaho Power system. *Estimated Cost: $300,000*
- Develop or procure an application that receives the request to dispatch DR resources and determines the specific points of service to curtail. *Estimated Cost: $75,000*
- Develop an application to enable the rapid and reliable dispatch of the appropriate DR resources. Currently, the systems used to dispatch DR reside on different networks and utilize different databases/data structures. The Company would need to ensure that information will be passed both securely and reliably between these systems. *Estimated Cost:* $50,000

Based on the required modifications, the total minimum upfront cost is estimated to be *$475,000;* however, the cost associated with the forecasting application could be higher depending on the specific DR programs that are selected. In addition to the upfront costs, there would be ongoing, annual costs associated with maintaining the upgraded and new systems. The annual cost associated with software maintenance and support is estimated to be $95,000, based on similar technology system projects that Idaho Power has completed and currently maintains.
It is expected that the life of the application will be approximately eight years before technology changes would require that it would have to be replaced or upgraded. It is projected that the cost of replacement or upgrade in eight years will be $150,000.

The projected timeline for implementing the modifications outlined above would be approximately six months to a year. This timeframe would provide for the ability to develop and verify the forecast, as well as providing adequate time to develop, test, and implement the other applications and integrations.

As discussed in the Applicability section above, in order to ensure that the DR resource would perform as required when dispatched to provide CRO, the Company would require that a program be designed and implemented for a two-year period of testing. Because Idaho Power would continue to utilize the resources that it currently uses to provide CRO during this testing period, the benefits of making these reserves available does not occur until the third year.

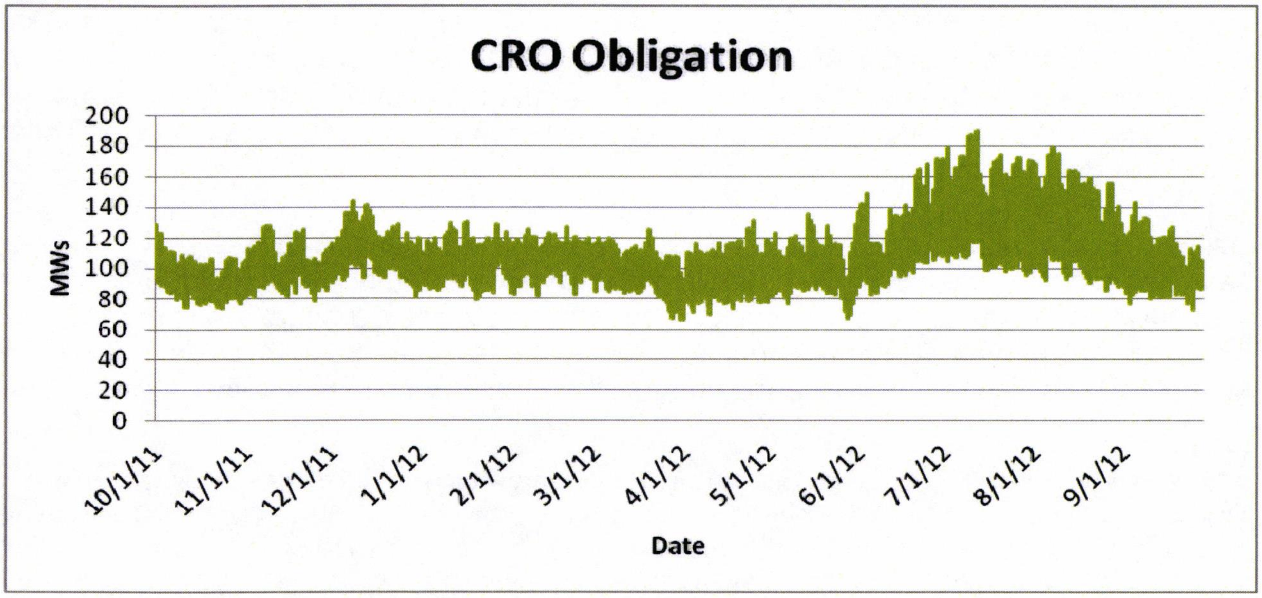
Benefits

To identify the potential benefits associated with using DR as CRO, the Company performed an analysis to quantify the dollar value of its CRO. The Company assumed levels observed during the 2012 Water Year (October 2011 through September 2012) for multiple system parameters, including system load, Mid-C prices, and natural gas prices. Water Year 2012 was selected for these parameters because the Snake River basin observed median-type stream flow conditions during Water Year 2012. Based on those assumptions, the Company conducted a study to determine the maximum dollar value of its CRO during a time period that DR could conceivably provide CRO. The time period utilized in the study assumes that DR could be available from mid-April through the end of September and valued the CRO during this time period at three different levels:

Results:

- Value of all of the non-spinning reserves. *Estimated Value:* *$578,212*
- Value of half of the non-spinning reserves. *Estimated Value:* *$363,678*
- Value of all of the heavy load hours non-spinning reserves (Monday through Saturday, 7 AM through 11 PM) *Estimated Value:* *$518,979*

The following chart represents the Company's total CRO during the time period studied. The maximum non-spinning portion of CRO identified by the Company's analysis was 96 MW.



Financial Analysis

The Company used the costs and benefits identified above to calculate an estimated annual levelized benefit and net present value of using DR as CRO. The annual levelized benefit amount is what the Company believes is the maximum incremental amount it could incur on an annual basis to use DR as CRO (for example to pay program incentives to participants or for program expenses), without financially harming other customers. In other words, if the annual levelized benefit amount was input in the financial analysis as an annual expense, the resulting net present value would be zero. The Company analyzed two scenarios for the Irrigation Peak Rewards program and a third scenario for the A/C Cool Credit program, which are presented below.

Based on the financial analysis performed for this Report, if the Irrigation Peak Rewards program were to provide all of the non-spinning reserves required from mid-April through September 30th at a 90 percent availability level,[12] the maximum incremental amount that Idaho Power could incur for participant incentives or program expenses would be $385,900 on an annual levelized basis. If the Irrigation Peak Rewards program were to provide all of the non-spinning reserves required during only heavy load hours from mid-April through September 30th at a 90 percent availability level, the maximum incremental amount that Idaho Power could incur for participant incentives or program expenses would be $336,400 on an annual levelized basis.

A current participant in the Irrigation Peak Rewards program receives an annual incentive of approximately $16 per kW of demand, which includes three dispatch events per season. For dispatch events beyond the first three, participants receive an energy payment based on the amount of demand reduction they are expected to provide during each dispatch event. If the Company were to design a program to be used as CRO, it would propose paying participants only fixed payments. The fixed payment structure would ensure that the Company does not make payments exceeding the annual levelized benefit amount. Additionally, because the CRO program would have an unknown and potentially unlimited number of events, the Company believes it would be imprudent to structure a program with a variable payment that would have the potential to exceed total benefits.

Using the scenario above where Irrigation Peak Rewards provides all of the non-spinning reserves required from mid-April through September 30th at a 90 percent availability level, the maximum amount the Company could design a program for is $385,900 on an annual levelized basis. This program would seek to achieve up to 96 MW of CRO and translates to a maximum $3.00 per kW of potential incentive.[13] The

[12] The Company does not believe it is reasonable to expect the Irrigation Peak Reward or A/C Cool Credit programs could provide 100 percent of the Non-Spinning reserves during the time studied. Ninety percent was selected to account for times when the programs would not be available due to factors such as mild temperatures and consecutive days of rain that would significantly impact whether participants would have irrigation pumps or A/C units turned on.

[13] For purposes of this report, the Company did not estimate total program costs to run a new CRO program. The actual amount available for participant incentives would be net of any program expenses incurred.

Company does not believe its irrigation customers would participate in a program that would have unlimited dispatch events, during all hours of the day, for only 20 percent of the incentive that the current Irrigation Peak Rewards participants are receiving from the traditional DR program.

Similarly, based on the financial analysis performed for this Report, if the A/C Cool Credit program were to provide approximately 35 percent[14] of the non-spinning reserves required during only heavy load hours[15] from mid-April through September 30th at a 90 percent availability level, the maximum incremental amount that Idaho Power could incur for participant incentives or program expenses would be $54,600 on an annual levelized basis. Under the current A/C Cool Credit program design, a participant receives an incentive of $15 per season, for no more than 60 hours of potential A/C cycling. Using the calculated annual levelized value of $54,600, the maximum Idaho Power could offer a participant in a CRO program is approximately $1.80 per season.[16] Here again, the Company does not believe its residential A/C customers would participate in a program that would have unlimited dispatch events for only 12 percent of the incentive that the current A/C Cool Credit participants are receiving from the traditional DR program.

Risks

Company Risk

It is critical to Idaho Power and the reliability of the BES that any CRO it maintains will undoubtedly perform as expected when it is dispatched, and the risks associated with not having a resource perform as projected cannot be understated. In the event that CRO is not responsive when activated, the Company is exposed to FERC, NERC, and WECC compliance violations as well as BES reliability issues that could negatively impact the electrical interconnection.

Part of the Operators' responsibly is to maintain system reliability, which is accomplished by various methods including the ability to shed firm load. The reliability to all of Idaho Power's customers could be impacted if a CRO resource does not perform when dispatched because the Operator may be required to activate the Load Curtailment and Interruption Procedure,[17] which could negatively impact some or all of Idaho Power's customers.

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[14] The 35 percent was selected based on: (33 MWs of potential program load reduction / 96 MWs maximum CRO required during this time).

[15] Because approximately 83 percent of residential A/C use occurs during heavy load hours, the Company did not calculate the annual levelized benefit derived from using an A/C program during all hours.

[16] For purposes of this report, the Company did not estimate total program costs to run a new CRO program. The amount available for incentives would be net of any program expenses incurred.

[17] I.P.U.C. No. 29, Tariff No. 101, Rule J, Continuity, Curtailment and Interruption of Electric Service, Original Sheet No. J-1: "Load curtailment and interruption carried out in compliance with an order by governmental authority shall follow the Company's plan entitled "Load Curtailment and Interruption Procedure," as filed with and approved by the Commission."

If unable to adhere to the NERC BES reliability standards, the Company could be exposed to significant fines, which could have a financial impact to the Company and its customers, with the most severe fines of $1,000,000 per occurrence or violation, per day.

DR Program and Participant Risk

Idaho Power's DR Programs provide both economic and operational benefits to the Company and its customers, and continuation of these programs is important to meeting one of the main objectives of the Company's Demand-Side Management objectives of providing demand reduction as determined through the IRP planning process. The DR Programs are identified in the IRP to help meet potential peak demands caused by extreme conditions in the summer, and the programs are relied upon to serve load and delay the need for building new peaking resources. The Company believes that the risk of impacting its current DR program participation levels is a critical component in the discussion of the overall feasibility of using DR as CRO.

As noted earlier in this Report, it should be emphasized that Idaho Power cannot predict or forecast when it will call on its CRO. Based on the historical data, it is clear the number of events can vary widely, with the number of times CRO was called on in the years of 2009 through 2013 ranging from 63 to 82. However, while those events should not be relied on to predict future events with any degree of certainty, the Company believes it is reasonable to assume that DR participants participating in a reserve-type program would be interrupted far more frequently that DR participants participating in a traditional DR program.

A/C Cool Credit

The Company believes that anytime it dispatches a DR event and cycles a participant's A/C unit off and on, there is a risk that the temperature in the participant's home will increase, creating discomfort and potentially some dissatisfaction with the program.[18] This effect would be amplified if an event were to be called twice on the same day, or even on high temperature consecutive days, as the home's A/C unit may not have been able to catch up from the first event. The Company believes that increasing the number of events a participant is exposed to through the combination of traditional DR A/C Cool Credit events and CRO events seems likely to decrease customer satisfaction, which could inevitably lead to customers opting out of the program. Losing participants both decreases the amount of DR the program is able to provide and places additional costs on the Company as most participants who opt out of the program insist on having the installed device removed.

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[18] On Monday, July 14, 2014, the Company called an A/C Cool Credit cycling event lasting three hours between 4:00 PM and 7:00 PM. The high temperature that day was 103 degrees. The Company received 63 phone calls from participants during the event and 127 calls from participants the day after the event. 117 participants decided to "opt out" of the program, effectively ending their participation in the program.

Irrigation Peak Rewards

Based on the number of times that Idaho Power calls on its CRO, the Company does not believe its irrigation DR Program participants would be willing to accept the unpredictability and number of interruptions that may occur in a given season. The potential number of interruptions (past data shows 63-82 times per year) exceeds what the Company believes an irrigation DR Program participants would tolerate without becoming very frustrated. Manual restarts of the irrigation pumps are utilized for roughly 50 percent of the systems currently enrolled in the program, and even for the participants who have an automatic re-start, the Company believes several of these participants manually check their irrigation systems for proper operation after any type of interruption. As discussed more fully above, Idaho Power calls on its CRO all days of the week at all hours of the day, which might mean that an irrigator would have an interruption that would require a manual restart or check in the middle of the night. Further, because the number of events called per day and duration of those events is unpredictable, participants could be negatively impacted. In fact, several short events are probably more disruptive to the typical irrigation DR Program participant than a single four hour event, as allowed under the current DR program parameters.

RECOMMENDATION

Based on its analysis, Idaho Power believes the operational and compliance risks outweigh the benefits to utilize DR as CRO because: (1) the economic benefit of using DR as CRO is too small to provide incentives at a level that would attract participation and provide for program costs, (2) the risks for failure to meet NERC standards is far greater than the economic benefit that might be derived, (3) the period of testing that would be required to provide operational certainty of compliance with NERC and WECC requirements would require carrying substantially more than the reserves actually needed for contingency, at a cost to all customers, and (4) the number of CRO events would put too heavy of a strain on the DR participants, thus risking participation in the Company's DR Programs.

The economic benefits, excluding payments to participants, of using DR as CRO are insignificant when compared to the capacity benefit the current DR Programs provide, and while having a dual-purposed program may be conceivable from a technical and compliance perspective, the Company believes that it is not practical from an economic and program participant perspective. The Company believes that the economic, DR program participation and other operational risks identified in this Report are too great to proceed with a pilot at this time. Therefore, the Company believes that it is not feasible to utilize its DR Programs for CRO.